Financing Options for Meeting Future Capital Requirements for MPEB

Interim Report

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CONTENTS

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CHAPTER 1

INTRODUCTION

1.1 An overview of the MPEB system

Installed capacity and generation

The Madhya Pradesh Electricity Board (MPEB) was formed in 1950 in pursuance of the Electricity (Supply) Act 1948. MPEB is the nodal utility responsible for power generation, transmission and distribution in the state of Madhya Pradesh. The installed capacity of the Board has grown from 708.9 MW in 1970-71 to 3283.7 MW as at the end of 1991-92; registering a compounded annual growth rate of 7.6 per cent. Electricity generated by MPEB mainly comes from thermal power plants which account for about 78 per cent of the total installed capacity. The gross generation of the Board has increased from 2806 MUs in 1970-71 to 12524 MUs in 1991-92. In addition to its own generating capacity, MPEB has a share of 1355.8 MW capacity from the Central sector generating projects and the electricity purchased there from presently accounts for nearly 33 per cent of the total units available for sale. Trends in growth of installed capacity and gross generation for MPEB are given in Figure 1.1 and 1.2 respectively.

Transmission and distribution system

MPEB operates one of the largest EHV transmission systems in the country, with the total line length of 17752 ckt. kms. as on 31st March 1991. This network is well interconnected to the neighbouring states to permit exchange of power. LT distribution lines have increased at the fastest rate of 12.7 per cent compounded per annum durng the period 1970-71 to 1990-91, and their share in total length of transmission and distribution lines has increased from 45.7 per cent in 1970-71 to 58.3 per cent in 1990-91 (refer Figure 1.3). The transmission and distribution losses were estimated at 24.89 per cent in 1990-91 (as given in the annual accounts).

Figure 1.1
Trends in installed capacity of MPEB

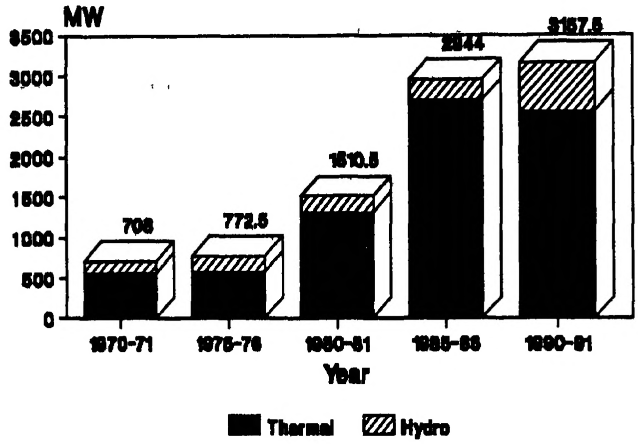
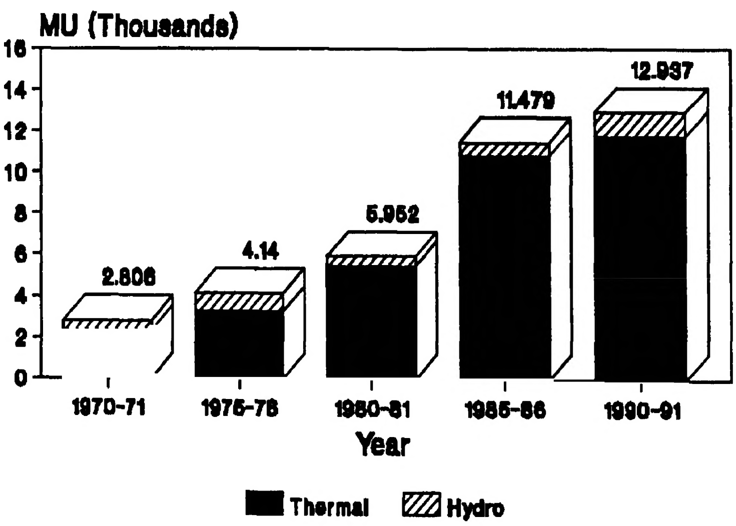


Figure 1.2
Trends in gross generation of MPEB



Energy sales

Electricity sales by MPEB has increased at a compounded annual growth rate of 10 per cent during the period 1970-71 to 1990-91. Per capita consumption has increased from only 45 kWh to 228 kWh during the same period. Over the years there has been a structural change in the pattern of electricity consumption. The share of HT-industries in the total electricity sales has declined from 74.57 per cent in 1970-71 to 51.5 per cent in 1990-91. On the other hand share of domestic sector has more than doubled from 7.3 per cent to 16.95 per cent, and that of agriculture sector has increased from 3.4 per cent to 17.2 per cent. The share of commercial sector has varied between 2 to 5 per cent. The remaining 11.13 per cent of the total sales in 1990-91 was accounted by public water works, railway traction, street lighting and bulk supply (refer Figure 1.3 for details).

Figure 1.3
MPEB's T&D network

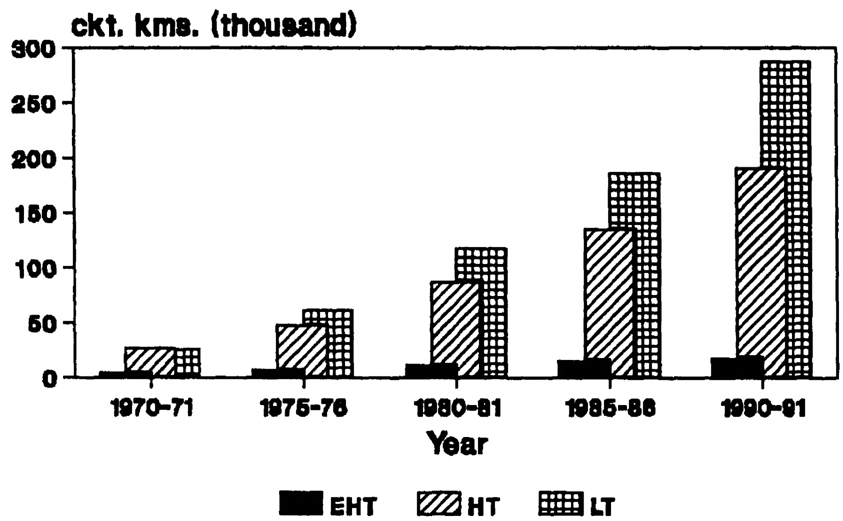
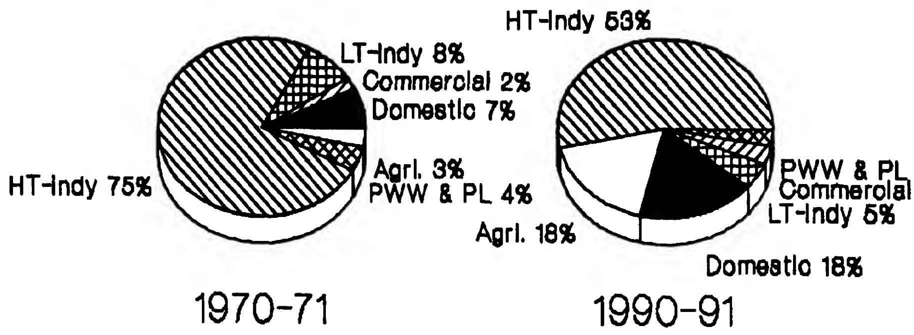


Figure 1.4
Sectoral electricity consumption in MPEB



Rural electrification

Since the mid sixties, the Board has accorded high priority to its rural electrification programme. Of the 70,883 villages, 88.9 per cent were electrified by the end of the Seventh Plan, covering almost 91 per cent of the rural population. During the Seventh Plan, village electrification targets were exceeded by 33 per cent. As on 31st March 1990-91, 0.9 million pumpsets have been energized, resulting in an increase in the state's irrigated acreage.

1.2 Power development during the Eighth Plan

The 14th Electric Power Survey Committee has projected that during the period 1992-2000, energy requirement and peak load in Madhya Pradesh is expected to increase at a growth rate of 11.8 per cent and 7.5 per cent respectively. The forecast indicates that during the terminal year of the Eighth Plan (1996-97), 28,104 MUs of energy will be required and the peak load is estimated to reach 4634 MW.

In order to meet this anticipated level of demand, MPEB has drawn up an ambitious plan for the growth and development of the power sector. Thirteen new projects (4 thermal and 9 hydro stations) with the total installed capacity of 4655.9 MW have been sanctioned for implementation. Of these, 1928.9 MW is proposed to be commissioned during the Eighth Plan This is lower than the anticipated capacity addition of 2922 MW as estimated by the 14th EPS. The shortages are therefore expected to be more than that projected by the report (refer Table 1.1). The Board has also chalked out a plan for renovation and modernization of its three existing power stations at Korba, Amarkantak and Satpura. The R&M schemes are expected to improve the availability of old generating sets, improve environmental conditions by reducing emissions, reduce furnace oil consumption etc.

Table 1.1: Anticipated power supply position during VIII Plan

	Unit	1992-93	1993-94	1994-95	1995-96	1996-97
Installed capacity	MW	3592 6	3934 6	3964 6	5199.6	6205.6
Peak Availability	MW	2808 3	3143 5	3302 0	3991.2	4582.3
Peak load	MW	3445.0	3734.0	4030.0	4321.0	4634.0
Surplus (Deficit)	MW	-636 7	-590 5	-728 0	-329 8	-51.7
Surplus (Deficit)	%	-18.5	-15 8	-18 1	-7.6	-1.1
Energy availability	MkWh	19746.9	21427 5	23352.1	24244.5	27892.5
Energy Requirement	MkWh	20878.0	22613 0	24391.0	26182.0	28104.0
Surplus (Deficit)	MkWh	-1131.1	-1185 5	1038.9	-1937.5	-211 5
Surplus (Deficit)	%	-5.4	-5.2	-4 3	-7 4	-0.5

MPEB plans to add 50,000 ckt. kms. of HT lines and 80,000 ckt. kms. of LT lines in the Eighth Plan. Additional capacity of 1260 MVA of 33/11 KV sub-stations and 2750 MVA of 11/0.4 KV sub-stations is envisaged during the Eighth Plan. The Board also plans to invest more resources in strengthening the sub-transmission and distribution network, improve the quality and reliability of the power supply, and reduce T&D losses. This has become even more necessary with the increase in the number of villages electrified and pumpsets energized. Under the RE

programme during the Eighth Plan, MPEB targets to electrify 6725 more villages and energize 2,50,000 new pumpsets.

In order to achieve the above targets, an investment requirement of Rs. 6887.23 crores is estimated. However, due to the severe financial constraints, only Rs. 3969.34 crores have been approved by the state government. This restricted outlay will not be adequate to provide fully even for ongoing and sanctioned projects and to take advance action on some of the Ninth Plan schemes. The shortage of financial resources is thus likely to severely affect the power supply position in Madhya Pradesh.

MPEB has achieved the 3 per cent rate of return (except in 1988-89, when the rate of return was -0.59 per cent) for several years as stipulated in the Electricity Supply Act. However an indepth analysis of the revenue account of the Board reveals that the financial health of the Board has declined since the mid-eighties. The operating ratio (defined as the ratio of total operating expenses to revenue from sale of power) has increased from 0.80 in 1985-86 to 1.00 in 1990-91. Consequently, the profit before subsidies has declined from Rs. 1.00 crore in 1985-96 to a loss of Rs. 141.88 crores in 1990-91.

Over the years MPEB has been financing increasing part of its capital expenditure from loans raised from the financial institutions. The state government loans accounted for only 8.9 per cent of the total capital expenditure in 1990-91 (lowest among all SEBs in the country). The interest costs of the Board has increased at a compounded annual growth rate of 17.6 per cent during the period 1985-86 to 1990-91. In 1990-91, interest costs accounted for 28 per cent of the total revenue expenditure of MPEB, as against 14 per cent in GEB and 19 per cent in MSEB. High interest costs in the per unit cost of generation and supply and coupled with the low rate of tariffs, further deteriorated the financial health of the Board. MPEB is therefore faced with an important issue of not only identifying the sources of finance for its future growth and development but options which would also ensure stability of the Board.

1.3 Need for the study

This study, therefore, proposes to look into the financing options available for meeting the future capital requirements as well as draw up a plan for the optimal utilization of the available resources. The specific terms of reference of the study are:

1. Identify options for financing capital requirements, with the objective of minimizing the cost of capital. This necessarily requires:
   - identification of sources of traditional and other borrowings;
   - identification of measures to increase internal resource generation;
   - studying the scope of tariff increase and additional resource generation;
   - identification of areas where reduced investment or dis-investment is justified;

2. Identify priorities for investment across areas. It is important that available capital is used efficiently and thus the need to prioritise investments. The optimal application of likely resources will be attempted in a base case resource forecast, high resource forecast and low resource forecast.

1.4 Structure of the report

Some options for financing capital requirements available to the Board are discussed in Chapter 2. This is followed by a chapter estimating the possible availability of resources to the Board by increasing tariffs and other measures such as reducing outstandings etc. An optimization model for prioritizing investments in generation projects follows in Chapter 4. A brief note on the Board's R&M activities is given in Chapter 5. The future work plan for the study is given in Chapter 6.

CHAPTER 2
FINANCING OPTIONS FOR MEETING CAPITAL REQUIREMENTS

2.1 Planning

Electricity is a concurrent subject in the Indian constitution, in which decision making and implementation involves both the Central and the state government. Traditionally, the central government provides the policy guidelines, regulatory and planning framework and the state governments are responsible for power development, generation and supply. The SEBs and the central sector power corporations function as public enterprises within the framework of national planning.

Formulation of individual projects is mainly carried out by the SEBs. However, in order to integrate their plans with the national plans the power utilities interact with the government at several stages. For all the power projects where the costs exceed Rs. 25 crores, a clearance is statutorily required from the Central Electricity Authority. The power sector organizations interacts with the Department of Coal, Department of Water Resources, Plan and Finance Division and the Project Appraisal division of the Planning Commission, Ministry of Environment and Forests etc. to obtain the necessary clearances and approvals to confirm fuel linkages. The Central Electricity Authority carries out optimization exercises to determine the least cost power addition option for the country as a whole. The output from this exercise becomes the national power plan.

The physical plan for power development is then translated into financial plan by the SEBs in consultation with the state governments. These are then submitted to the Planning Commission by the state governments as a part of their overall plan programme. Finally the allocation for the power sector out of the total plan resources is decided by the state government.

2.2 Sources of finance

Financing of the power sector projects is linked to the overall plan resources and allocation procedures. The plan resources are available in the form of:

* state government loans;
* market borrowings;
* loans from financial institutions;
* internal resources comprising profit before subsidies, revenue subsidies and grants, depreciation, consumer contributions, grants and subsidies for capital assets.

There is generally no equity available to the SEBs from the state government and the only equity available is reserves, surplus, consumer contribution towards cost of capital assets and the grants and subventions from the state government towards the cost of capital assets.

State Government loans

The state government provides long term loans to the electricity Board to finance its capital expenditure. These loans are generally treated as perpetual loans by the Board and are the cheapest source of borrowing - cost of borrowing of state government loan in MPEB was 10.25 per cent in 1990-91 as against the weighted average cost of borrowing of 16.15 per cent from the financial institutions. Also, as per the priority of charges laid down for payment of interest to state government, in the Electricity (Supply) Act, section 67(A), interest on the state government loans is to be paid only after meeting all the operating expenses, depreciation and payment of interest on all other loans.

An analysis of capital financing of MPEB during the period 1985-86 to 1990-91, reveals a declining trend in the share of state government loans; their share declined from 24 per cent in 1985-86 to 8.77 per cent in 1990-91 (refer Table 2.1 and Figure 2.1). Resource crunch and the poor financial health of the state government is often stated to be the reason for such a trend. Consequently, the Board has to resort to borrowings from the market and financial institutions,

resulting in an increasing interest burden on the Board. Interest on capital liability of MPEB increased from Rs. 178 crores in 1985-86 to Rs. 432 crores in 1990-91.

Table 2.1: Sources of financing capital expenditure (per cent)

Source	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
Internal resources	21.84	18.48	26 18	14.77	22.31	14.50
State government loans	24.27	20.83	19 15	16.48	11.31	8.77
Market borrowings	26.27	26.48	25.37	26.10	13.31	9.00
Loans from financial institutions	26.84	33.97	29.07	42.31	52.95	67 47
Other loans	0.78	0.24	0.24	0.34	0.13	0.27

In addition to the loans, state government also provides finances to the Board by way of market borrowings. The limits on this is governed by the Ministry of Finance and are fully guaranteed by the state government The date of issue of bonds and debentures as well as the amount to be floated is decided by the Planning Commission. The share of market borrowings in financing capital expenditure of MPEB has also declined from 26 per cent to 9 per cent during the period 1985-86 to 1990-91. Interest rate on market borrowings today stands at 13 per cent.

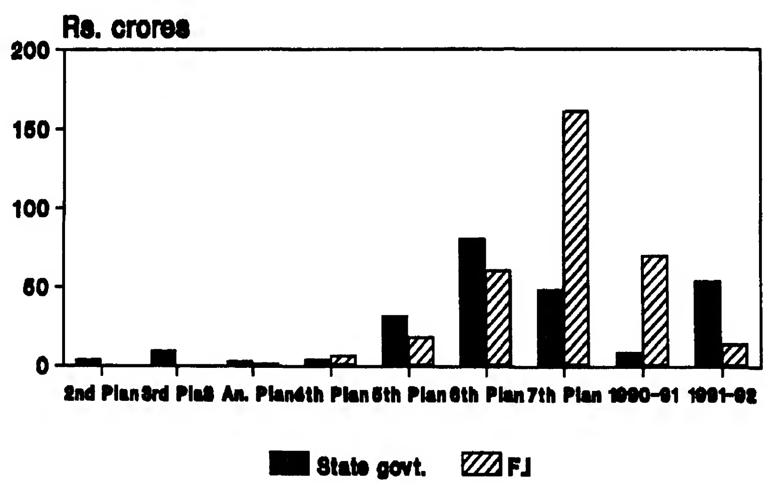
Loans from financial institutions

Increasing part of the total resources required by MPEB for capital expenditure has been raised through loans from the financial institutions. The share of loans from the financial institutions in the total capital requirement has increased almost two and a half times from 26.84 per cent to 67.47 per cent during the period 1985-86 to 1990-91.

LIC, UTI and GIC are the main sources of long term project financing for the SEBs. These loans are available at 14 per cent interest rate for a period of 15 years, against mortgage of assets. While the overall financing limit for these institutions are decided by the Planning commission for each state, limits for

various infrastructural and development sectors is decided by the state governments. This procedure is now under revision, and the financing limits will be laid down first on the sectoral basis (i.e energy, irrigation, education etc.) followed by limits for various states.

Figure 2.1
Funding of plans: state government & financial institutions



IDBI and IFCI give loans mainly to the private sector and primarily for industrial development. These institutions, in accordance with the charter, are reported to be not in a position to provide long term project finances to the SEBs. IDBI does provide support through their bill discounting scheme for suppliers of equipment. IFCI can offer support in the form of supplier's credit to equipment manufacturers. ICICI, SCICI (Shipping Credit and Investment Corporation of India) and Infrastructure Leasing and Finance Company can give loans to the power sector. In fact, these institutions are processing some proposals from private investors interested in the power sector. Interest rate of these loans range between 18-19 per cent.

MPEB, in the past has raised resources from ICICI, IDBI and LIC. Net loans to MPEB from IDBI, ICICI and LIC, as on 31st March 1991 were Rs. 120 crores, Rs. 55.8 crores and Rs. 60.84 crores respectively. The Board has not raised any resources from IFCI, UTI, GIC and SCICI and therefore may consider these institutions as options for financing its capital expenditure during the Eighth Plan. These institutions are reported to be willing to consider proposals from selected SEBs, provided the necessary guarantees or come up with alternate arrangements for timely repayment of their loans. It is likely that these institutions may have to get approvals from their respective Boards or general body before loans can be sanctioned.

REC loans are available to the Board for undertaking works associated with village electrification, energisation of pumpsets etc. These loans are available at 13 per cent interest rate (14.25 per cent for inventory loans). In MPEB, REC loans accounted for almost 20-22 per cent of the total loans raised from the financial institutions and this is expected to continue.

In addition to the above financial institutions the Board can raise resources from the Power Finance Corporation (PFC). PFC was set up in July 1986 to enable SEBs to raise resources outside the plan budget. The funds are not allocated to the states but are available for application to the SEB based on the merit of the project. PFC finances projects in the area of system improvements, renovation and modernisation projects, augmentation of transmission and distribution. Loans are granted for a period of 5 years and the present rate of interest is 16 per cent. PFC however stipulates certain conditions in regard to the financial position of the SEBs in order that they may be able to meet their debt-service obligations. One such condition is the SEB must adopt and implement the 'Operational and financial Action Plan' (OFAP) to improve its financial health. PFC's maximum exposure limits are set according to its client's creditworthiness and guarantees offered.

Other loans

In addition to the loans from financial institutions, MPEB has, in the past, also raised loans from other sources such as HUDCO, SIDBI, NVDC etc. for specific activities. The Board borrows from commercial banks for meeting their working capital requirements as well.

Assistance from multi-lateral institutions

MPEB has not received any assistance from institutions such as the World Bank or the Asian Development Bank. While the assistance from these institutions is at a substantially lower rate of interest (8.5-10 per cent), these loans have to be guaranteed by the Government of India and there is the element of foreign exchange rate risk. Also, these institutions normally insist on norms of operational efficiencies (such as reducing outstandings, rate of return, technical performance, environmental norms etc.), which the Boards are hesitant to accept readily. Getting projects cleared for support from these institutions takes anywhere between one to two years. Hence, MPEB must identify projects that could be submitted to these institutions for funding for the Ninth Plan and beyond. New projects that have received CEA clearance but are awaiting clearance from the environment ministry, should be given priority in getting the necessary clearance. These projects can then be processed without any further delay for submission to these institutions. Some of the projects in this category include the gas based power project at Gwalior, gas project at NFL, Guna, Raigarh TPS, Bina TPS Pench TPS extension, Korba (E) TPS extension stage III and Sanjay Gandhi TPS (extension). These funds are outside the normal resources available through the Plan outlay.

The Board has its own plan to improve efficiencies in generation, transmission and distribution as well as bring about improvements on the financial side. These institutions will require time-bound action plans for specific improvements and the Board must use this opportunity to emphasize their own commitment for carrying out these improvements and also to speed up their own

plans for improvements[1]. Assistance from these institutions will also permit access to international experiences and consultations through technical assistance component of the loans.

Internal resources

Internal resources primarily comprise provisions for depreciation fund, revenue surpluses, capital contribution from new consumers and grants and subsidies towards capital assets. Share of internal resources in financing capital expenditure has declined in MPEB from 21.8 per cent in 1985-86 to 14.5 per cent in 1990-91. It is evident from Table 2.2 that operating profit before taxes and excluding

Table 2.2: Details of internal resource generation (Rs. lakhs)

	1985-86	1986-87	1987-88	1988-89	1989-90	1990-91
Profit before revenue subsidies and grants	100	2812	-2224	-9201	-13544	-14188
Depreciation	6463	7282	8735	9829	10290	12501
Amortisation of intangible assets	383	0	0	0	0	0
Transfer to investment allowance reserves	-766	-5199	0	0	0	0
Revenue subsidies and grants	6400	6630	7350	8000	21162	21880
Contribution, grants and subsidies for capital assets	855	852	1268	1936	1874	2206
Funds utilised on working capital	-2351	-9481	-1729	-3429	-7475	-6838
Net funds from operation	11085	2896	13399	7134	12307	15561

[1]This holds true for Indian financial institutions as well.

revenue subsidies and grants fell from Rs. 28.12 crores in 1985-86 to an operating loss of Rs. 141.88 crores in 1990-91. The reason for this may be found in the widenening gap between average cost of generation and supply and average revenue realised per kWh. The deficit per kWh for sale of power increased from 2.87 paise in 1985-86 to 22.16 paise in 1990-91. Further, it is important to note that a significant portion of the internal resources is diverted towards meeting working capital requirements. Funds utilised on working capital increased at an annual compounded growth rate of 24 per cent during the period under consideration.

2.3 Comparison with other Boards

A comparison of the capital structure of MPEB during the Seventh Plan, with other utilities in the country reveals that the share of state government loans in MPEB was only 20.48 per cent as against the all-India average of 56.52 per cent. On the other hand, the share of institutional loans in MPEB was nearly 50 per cent compared to an all India average of 40 per cent. Share of internal resources (8.8 per cent) in MPEB, though positive (all India average was -10.52), was low compared to 9.46 per cent in RSEB, 11.68 per cent in MSEB, 15.01 per cent in KSEB, and 23.52 per cent in APSEB (refer Annexure 2.1 for details). As mentioned earlier, increasing dependence of the MPEB on the loans from financial institutions has resulted in increased cost of capital and high interest burden for the Board. During 1990-91, interest and finance charges accounted for 27 per cent of the total revenue expenditure in MPEB as against 19 per cent in MSEB and 14 per cent in GEB.

To conclude, the plan resources available to the Board from the state government are constrained by the state government's own financial health and the priorities across various infrastructural and development activities. Also limits imposed by the Planning Commission on UTI, LIC, and GIC for providing loans are beyond the control of the Board. The Board, however, can increase its internal resource generation through improvements in its operational efficiencies, cost reductions and rationalised tariff policies. This will also enhance the credibility of

the Board and thereby open more avenues of raising resources such as private financial institutions, multi-lateral banks and perhaps the Board may be able to raise resources from the market. Scope of tariff increase in MPEB and additional resource mobilisation are discussed in Chapter 3.

Annexure - 2.1

Pattern of financing capital expenditure during VII plan (1985-90)

(Rs. Crores)

S. No.	Board	Market Borrowing	Institutional structure	Internal Resources	State Govt. Loans	Total
1	Andhra Pradesh	2.18 (0.20)	271.85 (24.48)	261 18 (23.52)	575.19 (51.80)	1110 40
2.	Assam	241.52 (40.20)	109.45 (18.22)	-218.95 (-36.45)	468.80 (78.03)	600.82
3.	Bihar	282.01 (37.80)	370.68 (49 69)	-554.87 (-74.38)	648.24 (86.89)	746 06
4.	Gujarat	266.67 (16.43)	646 64 (39.84)	-380.83 (-23 46)	1090.57 (67.19)	1623 05
5.	Haryana	86.79 (12.93)	349 71 (52 09)	-452 82 (-67.45)	687 68 (102.43)	671.36
6.	Himachal Pradesh	46.21 (13.91)	76.02 (22 88)	-97.32 (-29.29)	307 38 (92.50)	332 39
7.	Jammu and Kashmir	64.34 (26.85)	64.53 (26.93)	-278 17 (-116.09)	388.90 (162.31)	239.60
8.	Karnataka Board	5.08 (0.91)	237 44 (42 52)	-207 64 (-37 18)	523.49 (93.75)	558.37
9.	Karnataka P.C.	12.93 (4.78)	220 94 (81 74)	-567 15 (-209 83)	603.56 (223 31)	270.28
10.	Kerala	52.25 (10.75)	212 19 (43 65)	73 02 (15 01)	148 71 (30 59)	486 17
11	Madhya Pradesh	513.69 (21 89)	1155.29 (49.23)	197 01 (8 40)	480.64 (20 48)	2346.63
12	Maharashtra	324 03 (10.05)	1415.70 (43.89)	376 87 (11 68)	1109 18 (34 38)	3225 63
13	Meghalaya	44.42 (37.36)	60.38 (50.78)	-27.28 (-22 94)	41.38 (34.80)	118 90
14	Orissa	0 03 (0.01)	267.17 (79 71)	28 82 (8 59)	39 17 (11 69)	335.19
15.	Punjab	103 59 (5 19)	146 71 (7.35)	-172.59 (-8 65)	1918.68 (96 11)	1996 39
16	Rajasthan	199.87 (16.89)	393.34 (33 25)	111 90 (9 46)	477.91 (40 40)	1183 02
17	Tamil Nadu	252 46 (12.02)	1015.01 (48.32)	-140.66 (-6.69)	973.62 (46 35)	2100 43
18	Uttar Pradesh	206.21 (8.55)	1031.04 (42 74)	-38.95 (-1 62)	1214.33 (50 33)	2412.63
19	West Bengal	242 79 (39.83)	330.25 (54 18)	-117.59 (-19.29)	154.09 (25.28)	609.54
	Total	2947.07 (14.06)	8374.34 (39.94)	-2206 02 (-10 52)	11851.52 (56.52)	20966.91

Source· Annual Report on the Working of State Electricity Boards and Electricity Departments, Planning Commission, Government of India, August 1992

CHAPTER 3

OPTIONS FOR INCREASING INTERNAL RESOURCES THROUGH TARIFFS

3.1 Review of tariffs

Electricity tariffs in MPEB, as in most of the State Electricity Boards in the country, have not been able to meet the average cost of supply. The tariff policies and revisions have been guided more by social or/and political considerations rather than financial and economic efficiency objective. The overall average revenue realised by MPEB continues to be below the average cost of generation and supply of electricity. In fact the ratio of average revenue realised to average cost of generation and supply has declined from 0.87 in 1985-86 to 0.71 in 1990-91. Details of average cost of generation and supply and average revenue realised from major consumer categories during the period 1985-86 to 1990-91 is given in Table 3.1. It is evident that the agriculture and the domestic consumers are supplied electricity at a highly subsidised rate and the extent of subsidies has increased over the years. The electricity rates for agriculture sector were reduced and flat rate tariff was introduced in 1988-89. This resulted in a sharp increase in the electricity consumption by the agriculture sector. However, the average revenue realised from this sector declined from 24.35 paise/kWh in 1988-89 to 19.47 paise/kWh in 1989-90, and further to 15.03 paise/kWh in 1990-91.

Another major area where the Board incurs a loss is large number of single point connections given in the jhuggi-jhopdi in urban areas as well as tribals and harijans in the rural areas. On an average 2.45 lakhs single point connections are given by the Board every year (estimated for the period 1986-87 to 1990-91). Consequently, the average per unit revenue realised from the domestic sector has declined from 42.10 paise in 1985-86 to 28.23 paise in 1990-91. Average revenue realised from public lighting has also declined from 86.08 paise/kWh to 61.48 paise/kWh during the period under consideration.

Table 3.1:	**Consumer categorywise average revenue realised and average cost of generation and supply of electricity for MPEB (paise/kWh).**					
Category	**1985-86**	**1986-87**	**1987-88**	**1988-89**	**1989-90**	**1990-91**
Domestic	42.10	37.69	28.64	27.99	26.55	28.23
Commercial	98.21	99.36	97.99	104.91	109.53	109.23
Agriculture	26.39	24.18	23.28	24.35	19.47	15.03
LT-industry	70.40	104.47	83.31	87.02	94.34	98.07
HT-industry	71.36	78.69	91.70	105 26	112.98	126.73
P.Lighting	86 08	61.35	78.12	71.53	24.86	61 48
P.W.W	20.20	20.58	22.17	23.04	21.89	26.46
Traction	46.99	52.55	91.30	99.01	121.57	158.17
Inter state	70.32	75.64	76.82	80.46	93.46	80.83
Average revenue	63.94	68.30	72.24	77.89	78.83	83.41
Avg. cost	66 81	71.05	79 29	93.71	102.02	105 57

In order to partially make up the losses incurred by the Board as a result of supplying electricity at a subsidised rate to the agriculture and domestic sector, HT consumers are often charged a rate higher than the cost of supply to them. The average revenue realised from the railway traction has increased at a compounded annual growth rate of 27.47 per cent during the period 1985-86 to 1990-91. The growth rate of average revenue realisation from the HT-industries and LT-industries was 12.17 per cent and 6.85 per cent respectively during the same period.

Tariffs have been revised with effect from August 1992. The full impact of these revisions will be felt only in 1993-94.

3.2 Comparison with MSEB and GEB

Comparison of tariffs for various consumer categories in 1990-91 for MPEB, MSEB and GEB and their growth rates during 1985-86 to 1990-91 are given in Table 3.2 and 3.3 respectively. It is evident that average revenue realised from all consumer

categories in MPEB, (except railway traction) was lower compared to that in GEB and MSEB. In particular, tariffs for the domestic sector and public water works are very low in MPEB. During 1990-91, domestic sector was given a subsidy of 73 per cent of the average cost of supply, while the subsidies provided in GEB and MSEB were 27 per cent and 38 per cent respectively. It is important to note that during the period 1985-86 to 1990-91 average revenue realised from domestic sector in MPEB has declined at a rate of 8 per cent compounded per annum, while in MSEB and GEB it increased at the growth rate of 10 per cent and 3.56 per cent respectively. The subsidy to the public water works in MPEB was also high at 75 per cent in 1990-91. The agriculture consumers pay only 15 per cent of the cost of generation and supply in all the three states. While the average revenue realised from this sector in MSEB increased at the rate of 10 per cent per annum during the period 1985-86 to 1990-91, it declined significantly in MPEB and GEB.

On the other hand, commercial consumers pay 103 per cent of the average cost of generation and supply in MPEB as against 155 per cent in GEB and 128 per cent in MSEB. The average revenue realised from this category increased at a compounded growth rate of only 2.1 per cent during the period 1985-86 to 1990-91 in MPEB, while the growth rate was 14.41 per cent and 11.59 per cent for GEB and MSEB respectively.

Similarly for the HT industries, the ratio of average revenue realised to average cost of generation and supply was the lowest in MPEB among all three Boards. LT-industries are supplied power at subsidised rate in MPEB, while in GEB these industries pay 32 per cent more than the average cost of generation and supply. The growth rate of per unit average revenue realised from LT and HT industries was lowest in MPEB.

Table 3.2: Comparison of consumer categorywise average revenue realised in 1990-91 across MPEB, GEB and MSEB (paise/kWh).			
Consumer category	**MPEB**	**GEB**	**MSEB**
Domestic	28.23 (73)	81.00 (27)	71.00 (38)
Commercial	109.03 (-3)	173.00 (-55)	147.00 (-28)
Agriculture	15.03 (86)	16.00 (86)	15.00 (87)
LT-Industry	98.07 (7)	147.00 (-32)	114.00 (0)
HT-Industry	126.73 (-20)	155.00 (-39)	158.00 (-38)
P.Lighting	61.48 (42)	96.00 (14)	79 00 (31)
P.W W	26.46 (75)	61.00 (45)	124.00 (-8)
Traction	158.17 (-50)	124.00 (-11)	129.00 (-13)
Inter state	80.83 (23)	121 00 (-8)	72.00 (37)
Total	83.41 (21)	91 00 (18)	109 82 (4)

Table 3.3: Rate of growth of per unit average revenue realised from various consumer categories during the period 1985-86 to 1990-91 (per cent).			
Consumer category	**MPEB**	**MSEB**	**GEB**
Domestic	- 8.00	10.04	3.56
Commercial	2.11	14.41	11 59
Agriculture	-11.00	10 75	-21 00
LT-Industry	6.85	14.47	9.12
HT-Industry	12.17	12.93	14.14
P.Lighting	- 7.00	14.02	7.14
P.W.W	5.55	10.88	- 3.00
Traction	27.47	16.54	12.77
Inter state	2.80	3 37	10.04
Total	5.46	12 11	3.39

3.3 Additional resources through tariff revisions

As discussed above, electricity tariffs in MPEB, offer substantial scope for rationalization. Tariffs must be reviewed annually to reflect the true cost of

generation and supply. It is suggested that, the average per unit revenue must recover the average cost of generation and supply and in addition enable the Board to earn 3.5 per cent rate of return. Increase in average per unit revenue required to meet these objectives are estimated in Table 3.4. The calculations are based on the following assumptions:

(1) Consumer category wise sale of electricity is obtained from the report of the 14th Electric Power Survey Committee.

(2) Average revenue realised from various consumer categories are based on the tariff structure in force since August 1992.

(3) Average cost per kWh is assumed to increase at the compounded growth rate of 4.05 per cent as registered during the period 1989-90 to 1990-91.

(4) Average revenue outstandings of MPEB, in assumed to be 20 per cent of the revenue expenditure in any year. This assumption is based on the trend observed during 1990-91 and 1991-92.

(5) Additions to gross fixed assets is estimated on the basis of the schedule of commissioning of new power stations. In the case of transmission and distribution, 70 per cent and 80 per cent respectively, of the capital expenditure in any year is assumed to be converted into assets. Capital expenditure on renovation and modernisation of the existing power stations is also considered while estimating gross fixed assets.

It is estimated that the Board will need an additional Rs. 537.68 crores to earn 3.5 per cent rate of return on net fixed assets for the year 1993-94. This translates into an average tariff increase of Rs. 0.26 per kWh over the current rates in force and represents a rise of 22 percent over the average revenue realised as compared to tariffs in force currently. The Board is compensated by the state government for supplying electricity at subsidised rates to some categories of

consumers in the rural areas. If the past trend of revenue subsidies from the state government continue (20 per cent of the revenue realisation), the average tariff increase required is only 7 paise per kWh. However, it is suggested that MPEB should gradually reduce its dependence on the revenue subsidies from the state government and streamline its tariff policies. This will also provide the Board with greater autonomy.

In 1990-91, the revenue outstandings of the Board was 20 per cent of the total revenue. Financial institutions in India and the multilateral institutions recommend that the outstandings should not exceed 60 days of revenue from energy sales. It is estimated that a decline in the outstandings from the present level of 20 per cent of the revenue to 16.5 per cent, will reduce the tariff increase required by 4 paise/kWh to achieve 3.5 per cent rate of return (refer Table 3.4).

Additional resources that can be available to MPEB, through tariff revisions are given in Table 3.5. Three scenarios - Case I, II and III, are worked out assuming rate of return of 3.5 per cent, 5 per cent and 7 per cent respectively (the Ninth Finance Commission had recommended that the Boards earn a 7 per cent rate of return). Internal resource generation is defined as the sum of net profit, depreciation, and consumers contributions, net of funds utilised for working capital. It is assumed that a maximum of one-fourth of the total working capital required in any year (estimated as one-sixth of the operating expenditure), will be provided from the internal resources available to the Board. These resources may be utilised for loan repayments and capital expenditure on new projects. Assuming a capital structure comprising 75 per cent of loans from financial institutions and a ratio 0.5 of loan repayment to new loans raised in any year (assuming that the repayments do not exceed the internal resources of the Board for that year), the net internal resources available to the Board for capital expenditure is estimated to be Rs. 93.98 crores during the Eighth Plan for Case I. Additional resources available to the Board under Case II and Case III are estimated to be Rs. 380.57 crores and Rs. 762.7 crores respectively.

Table 3.4:	**Additional resources that can be raised by MPEB through tariff increases**				
	1992-93	**1993-94**	**1994-95**	**1995-96**	**1996-97**
Sales (MUs)	15916	17343	18826	20208	21692
Revenue expected (Rs. lakhs)	189312	203802	218986	234697	251519
Revenue realised (Rs. lakhs)	151449	163041	175188	187758	201215
Other income (Rs lakhs)	9749	11037	12495	14145	16013
Total revenue (Rs lakhs)	161199	174079	187683	201903	217228
Average cost/unit (Rs/kWh)	114	118	123	128	133
Total cost (Rs. lakhs)	198404	240000	294581	367154	464828
Rate of return (3.5%) (Rs lakhs)	11643	12153	13013	14039	17141
Tariff increase (Rs/kWh)	0 20	0.26	0.31	0.36	0.42
Tariff increase with 20% RE subsidy (Rs/kWh)	0.01	0.07	0.12	0.17	0.23
Tariff increase with 16 4% revenue outstandings (Rs/kWh)	0.16	0.21	0.27	0 32	0.38

Table 3.5:	**Additional resources available to MPEB from internal resource generation (Rs. lakhs)**					
	1992-93	**1993-94**	**1994-95**	**1995-96**	**1996-97**	**Total**
Case I: 3.5% Rate of return						
Internal resource generation	25198	26986	29578	35372	41114	158248
Capital requirement	59834	68400	78000	89000	101700	396934
Loan repayment	22438	25650	29250	33375	38138	148850
IRG/Total capital requirement	0 31	0 29	0 28	0 29	0 29	0
Net IRG	2760	1336	328	1997	2976	9398
Case II: 5% Rate of return						
Internal resource generation	30188	32099	34997	41181	48443	186908
Capital requirement	59834	68400	78000	89000	101700	396934
Loan repayment	22438	25650	29250	33375	38138	148850
IRG/Total capital requirement	0 37	0 34	0 33	0 34	0 35	0
Net IRG	7750	6449	5747	7806	10306	38057
Case III: 7% Rate of return						
Internal resource generation	36841	38915	42223	48926	58216	225120
Capital requirement	59834	68400	78000	89000	101700	396934
Loan repayment	22438	25650	29250	33375	38138	148850
IRG/Total capital requirement	0 45	0 41	0 39	0 40	0 42	0
Net IRG	14404	13265	12973	15551	20078	76270

3.4 State electricity duties

State electricity duties (SEDs) are the levies charged by the state government which are payable by the consumer in addition to tariffs. The incidence of SED as well as the absolute amount of SED paid in MPEB is highest among all the SEBs in India. SED as a proportion of revenue from sale of power in MPEB increased from 6.2 per cent in 1985-86 to 13.3 per cent in 1990-91. This must be viewed against an all-india figure of 5.47 per cent in 1990-91 (refer Annexure 3.1). In absolute terms, SED increased from Rs. 45 crores in 1985-86 to Rs. 155 crores in 1990-91, at a compounded annual growth rate of 30 per cent. This works out to be 6 per cent of the capital base in 1990-91, as against 1.5 per cent as recommended by the Venkatraman Committee (1965). The corresponding figure for MSEB was 3.3 per cent and the average taken across all SEBs was 2.7 per cent.

Increasing incidence of SED limits the scope for tariff revision by the SEB, as the ultimate burden on the consumer is always taken into account while fixing tariffs. It can be seen from the Table 3.6 that in the case of domestic and commercial consumers, SED has been increasing while there has been no revision

Table 3.6: Electricity tariff and electricity duty in MPEB (paise/kWh)

Category	1985-86	1986-87	1987-88	1988-89	1989-90
Domestic (30 kWh/month)					
Rate	40.00	40.00	40.00	40.00	40 00
ED	07.00	08 00	08.00	09.00	09 00
Commercial (200 kWh/month)					
Rate	90.00	90.00	90.00	90 00	105.00
ED	11.50	13 50	18.00	19.00	19 00
Small indy (5 HP, 10% LF)					
Rate	55.00	60.00	60.00	75.00	75.00
ED	05.00	05.00	05 00	05 00	06 00
Large indy (1000 kW, 50% LF)					
Rate	51.62	61.53	61 53	69.63	69.63
ED	04.00	05.00	08.00	12.00	12.00

Source: Average electric rates and duties in India, Central Electricity Authority, ETA&A Directorate, April 1990

in the rate for electricity. Further, while the SED is an additional source of revenue to the state exchequer, the generation of this additional revenue is not taken into account in assessing the profitability of the Board. It is therefore suggested that, SED should be determined as a proportion of the capital base (1.5 per cent), and a portion of the additional amounts realised by the state governments as electricity duty should be given to the Board as long term finance for capital projects.

3.5 Need for subsidising rural electrification losses

The Board incurs substantial losses on account of providing electricity at a subsidised rates to domestic, agriculture, water works and street lighting consumers in rural and remote areas. These losses are to be compensated by the state governments under the rural electrification programme. However in practice the SEBs often complain of non-payment of RE subsidies or partial payment after substantial delays. As on 31st March 1991, Rs. 263.35 crores were outstanding to MPEB on account of RE programme (refer Annexure 3.2). Non-payment or partial payment seriously affects the financial viability of the Board since they have to resort to heavy market borrowing to meet the shortage of funds. It is therefore suggested that the state government must take action to liquidate the outstanding subsidies on a time bound basis, make an arrangement by which SEBs are regularly paid their subsides quarterly in advance subject to periodical re-adjustment on the basis of claims submitted by the Board. It is further suggested that the process of estimating subsidies be more transparent in order that the state government can have a better understanding of the calculation of subsidies.

3.6 Recovery of outstanding dues

One of the key factors in the efficient financial performance of the Board is its prompt collection of dues. The revenue arrears as a proportion of revenue receipts increased from 20 per cent in 1985-86 to 30 per cent in 1990-91. The debtors turnover ratio increased from 77 days to 110 days during the same period.

Revenue outstandings improved in 1991-92 to Rs. 290.64 crores, accounting for 20 per cent of the revenue sales during the year. Textile mills and the state water works department together accounted for 51 per cent of the total outstandings as on March 1992, and dues from sale of power outside the state accounted for 23 per cent of the total outstandings (refer Table 3.7). It is suggested that the revenue outstandings in any year should not be more than 16 per cent (60 days average) of the revenue receipts. Disconnection notices should be issued by the Board in respect of textile mills and public water works department, with more than three months of outstandings. Cases pending in the courts must be expedited.

Further, it needs to be pointed out that out of Rs. 290.64 crores, due from the consumers, Rs. 115.11 crores pertains to the surcharge levied for delayed payment/non-payment of energy charges. Till December 1990, the Board was levying 2 per cent surcharge per month on compound interest basis for delayed payments. From January 1991, this was changed to 2 per cent simple interest, as an incentive to the consumers to come forward to settle their dues. Consequently, the total surcharge of Rs. 115.11 crores due as on March 1992, is expected to be reduced by 50 per cent.

Table 3.7: Details of outstandings as on March 1992 (Rs. crores).

Categories	Energy charge	Surcharge	Total
Textile mills	34.16	73.23	107.39
J.C. Mills	1.53	0.18	1.71
BALCO	5.74	-	5.74
Water works	57.97	27 38	85.35
RE cooperative society	1 56	0 91	2.47
Connected consumers	43 80	7 02	50 82
Disconnected/unconnected consumers	30.77	6 39	37.16
Total	175 53	115.11	290 64

It must be pointed out that the oustandings from LT consumers as at end of March 1992 was only 28.8 crores, which was about 10 per cent of the total outstandings. Out of this, 70 per cent of the outstandings were due for more than 6 months[1]. It is of utmost importance that the Board initiates steps to recover the outstandings that are overdue by more than 6 months. Improving the outstandings also brings down the extent to which tariff revision is required from 26 paise/kWh to 21 paise/kWh (refer Table 3.2).

[1]The outstandings of Rs. 7.99 crores (as on March 1992), which was outstanding for less than 6 months, must be seen in the context of the total revenue of Rs. 321 crores from the LT consumers for 1991-92.

Annexure - 3.1

State electricity duty (SED) as proportion of average revenue

(Paise/kWh Sold)

S. No.	Board	1989-90			1990-91		
		Average Rate	SED	(%)	Average Rate	SED	(%)
1	Andhra Pradesh	66 65	2.33	3 50	74 80	2 25	3 01
2.	Assam	87.87	1 77	2 01	94.84	2 04	2.15
3.	Bihar	86.80	1 90	2.19	92 21	1 90	2 06
4	Gujarat	81 10	9 68	11 93	81 45	9 71	11.92
5	Haryana	58.68	5 06	8 62	82.40	6 19	7.51
6.	Himachal Pradesh	64 56	2 54	3 93	79 13	2 20	2.78
7	Jammu and Kashmir	40.23	4 90	12 18	38.00	4 30	11 32
8	Karnataka	65 80	5 35	8.13	79 70	5 47	6.86
10	Kerala	55.00	7 58	13 78	53 04	7 35	13 86
11	Madhya Pradesh	83.72	13 43	16 04	83 15	13 43	16 15
12.	Maharashtra	83 22	4 37	5 25	103 06	4 35	4 22
13	Meghalaya	50 30	0 65	1.29	59 21	0.85	1 43
14	Orissa	65 78	11.16	16 97	72.38	11.34	15 67
15	Punjab	46.90	4.22	9 00	54 87	4 53	8 26
16	Rajasthan	76 67	4.85	6 33	89 27	4 86	5 44
17	Tamil Nadu	73 34	-	-	85 13	-	-
18	Uttar Pradesh	71 47	2 37	3 32	73 09	2 34	3.20
19	West Bengal	103 43	1 85	1 79	103 51	1 84	1 78
	All Board's Average	74 62	4 84	6 49	77 84	4.26	5.47

Source Annual Report on the Working of State Electricity Boards and Electricity Departments, Planning Commission, Government of India, August 1992

Annexure - 3.2

Rural electrification subsidy

(Rs. Crores)

Year	Amount of subsidy due as claimed by the Board	Subsidy actually received from the State Govt.	Progressive arrears
1973-74	5 00	5 10	0.10
1974-75	5.70	5 60	-
1975-76	8 10	8.10	-
1976-77	10 70	10 70	-
1977-78	14.10	19 06	4 96
1978-79	25 90	25 10	4 16
1979-80	34.30	28.02	-2 12
1980-81	51 00	22 89	-30 23
1981-82	60 50	40 00	-50 73
1982-83	63.80	55 00	-59.53
1983-84	72.20	57 00	-74 73
1984-85	95 60	64 00	-106 33
1985-86	73.83	66 00	-114 16
1986-87	89 47	73 00	-130 63
1987-88	97.08	80.00	-147.71
1989-90	211 50	204 18	-264 16
1990-91	218 80	219.61	-263 35

CHAPTER 4

A MODEL FOR PRIORITIZING GENERATION INVESTMENTS

4.1 Need for prioritizing

One of the main problems faced by the Board is that of competing investment works, which are essential but cannot be taken up due to paucity of funds. Poor availability of resources often results in time overruns which further escalates the cost of the project. As against the normal gestation period of 48 months for coal based power stations, MPEB has taken anywhere between 61 to 82 months to complete the projects. Due to pressures to meet the demand, generation projects invariably get priority over transmission and distribution. In the eighties, generation projects accounted for 50-55 per cent of the total capital expenditure, about 20 per cent of resources were spent on transmission and distribution projects. RE schemes accounted for about 25 per cent of the total capital expenditure. Inadequate investments in transmission and distribution is often regarded as the main reason for high T&D losses and poor quality of power supply. Works relating to system improvements and planned maintenance are generally postponed due to limited availability of resources. The objective therefore would be to maximize the benefits from the investments, which would enable the Board to prioritize the investments across various capital works. Prioritisation is required at two stages:

(i) prioritisation of investments across activities: generation, transmission, distribution, system improvement, renovation and modernisation etc.

(ii) within each activity, prioritisation is required among the competing projects.

The Board invests in capital assets with a view to either: (a) meet additional demand for energy; (b) improve the reliability of the power system; (c) improve operating efficiencies in generation, transmission and distribution; (d) to

provide better quality of power. Since funds available are limited, there arises the need to prioritize the activities of the Board in order to get the maximum benefits out of the limited funds available.

Since the objective is to maximize the benefits, the first step is to be able to quantify the benefits arising out of these investments. While quantifying benefits is direct in the case of generation (in terms of units generated or revenue realized), it becomes complicated to do so in the case of transmission and distribution where it is not possible to allocate the benefits of power being transmitted and distributed. In the case of (b) and (d) above, there exist no direct and simple way to quantify the benefits. Hence, a model for prioritisation of investments is presently limited to generation projects. Net benefits for generation projects are defined as:

Net Benefit	=	Gross benefit - Cost			
	=	Revenue from sale of energy generated	-	variable cost of generation	fixed cost of investment

Benefits are calculated as revenue from sale of energy. The fixed cost is the capital cost of investing in new capacity. The variable cost is linked to generation and consists of fuel costs but also maintenance, salaries of employees in generation, and other administration overheads. Thus, it is necessary to understand how the various components of the variable costs are affected by changes in the level of generation. A methodology to study this relationship is dealt with in the next section.

4.2 Variable cost analysis

Methodology

The total generation Q in MUs is represented by the following functional relationship:

$$Q = f(F, L, M, K)$$

where

F	-	is the fuel input
L	-	is the labour input
M	-	is the materials used
K	-	is the capital stock
f		specifies a functional relationship

Corresponding to every production function, there exists an cost function which can be expressed as:

$$C = f(p_F, p_L, p_M, p_K, Q)$$

where

p_F is the price of fuel

p_L is the price of labour

p_M is the price of materials

p_K is the price of capital

Q is the output level

In the analysis of variable cost, capital stock already exists, and thus the cost of capital has to be paid irrespective of the level of generation. In such a case, changes in the cost of capital will not have any effect on generation levels[1]. Thus, the stock of capital is used as a parameter in place of the price of capital. The variable cost function is of the form

$$VC = f(p_F, p_L, p_M, Q, K)$$

[1] In the overall cost function, the assumption is that any change in the input prices, can induce a change in the cost by either the producer choosing to consume less of the input or shift to more inexpensive inputs. The cost is flexible in the outputs but when a certain input is constrained to be fixed, then no change in the level of input is possible.

The next step is to specify a functional form for the variable cost function. The "Transcendental Logarithmic Form" (referred to as the TRANSLOG function)[2] has been used in a number of industry related studies, note worthy of them being one relating to the energy sector by Berndt and Wood[3]. A specific use of the translog function for the electricity sector has been carried out by Nelson[4]. The translog function is represented as follows:

$$
\begin{aligned}
Log\ VC = {} & \alpha_O + \alpha_F LogP_F + \alpha_M logP_M + \alpha_L LogP_L + \frac{1}{2}\alpha_{FF}(logP_F)^2 \\
& + \alpha_{FL} logP_F LogP_L + \alpha_{FM} logP_F logP_M + \frac{1}{2}\alpha_{MM}(logP_M)^2 \\
& + \alpha_{MF} logP_M logP_F + \alpha_{ML} logP_M logP_L + \frac{1}{2}\alpha_{<}(logP_L)^2 \\
& + \alpha_{LF} logP_L logP_F + \alpha_{LM} logP_L logP_M + \beta_Q logQ \\
& + \frac{1}{2}\beta_{QQ}(logQ)^2 + \beta_{QF} logQ logP_F + \beta_{QM} logQ logP_M \\
& + \beta_{QL} logQ logP_L + \gamma_K logK + \frac{1}{2}\gamma_{KK}(logK)^2 \\
& + \gamma_{KF} logK logP_F + \gamma_{KL} logK logP_L \\
& + \gamma_{KM} logK logP_M + \gamma_{KQ} logK logQ
\end{aligned}
$$

[2]See Christenson, L.R., Jorgenson, D.W. and Lau, L.J. (1973) "Transcendental Logarithmic Production Frontiers," *Review of Economics and Statistics*, Vol. 55.

[3] Berndt, E R. and Wood, D.O. (1975) "Technology, Prices and the Derived Demand for Energy," *Review of Economics and Statistics*, Vol. 57.

[4] Nelson, Randy (1990) "Capacity Utilisation in Electric Utilities," *Journal of Industrial Economics*.

or, in short

$$
\begin{aligned}
Log\ VC = {} & \alpha_O + \sum_i \alpha_i logP_i + \frac{1}{2}\sum_i \alpha_{ii} logp_i + \sum_i\sum_j \alpha_{ij} logP_i logP_j \\
& + \beta_Q logQ + \frac{1}{2}\beta_{QQ}(logQ)^2 + \sum_i \beta_{Qi} logQlogP_i \\
& + \gamma_K logK + \frac{1}{2}\gamma_{KK}(logK)^2 + \sum_i \gamma_{Ki} logKlogP_i \\
& + \gamma_{KQ} logKlogQ \qquad for\ i = F, M, L
\end{aligned}
$$

Here all α, β, γ are coefficients, the directions and magnitude of which will determine the effect of a change in input prices $P_{i,}$ on the variable cost, or the effect of a change in increasing generation on the variable cost. These coefficients are estimated, using available data on VC, $P_{i,}$ Q, and K.

If logVC is differentiated with respect to the logarithm of the respective prices, the cost share equations are obtained as below.

$$\frac{\partial \log VC}{\partial \log P_F} = \alpha_F + \alpha_{FF}\log P_F + \alpha_{FM}\log P_M + \alpha_{FL}\log P_L + \beta_{QF}\log Q + \gamma_{KF}\log K$$

$$\frac{\partial \log VC}{\partial \log P_M} = \alpha_M + \alpha_{FM}\log P_F + \alpha_{MM}\log P_M + \alpha_{ML}\log P_L + \beta_{QM}\log Q + \gamma_{KM}\log K$$

$$\frac{\partial \log VC}{\partial \log P_L} = \alpha_L + \alpha_{LF}\log P_F + \alpha_{LM}\log P_M + \alpha_{<}\log P_L + \beta_{QL}\log Q + \gamma_{KL}\log K$$

The three cost share equations along with the variable cost equation form a multivariate system of equations, which are estimated as a simultaneous system of equations, since they are all dependant on one another. Since one of the cost shares can be obtained as a residual of the sum of the other two, one of the equations can be dropped. The system of equations to be estimated using econometric analysis techniques are then the variable cost equation, the fuel cost equation and the materials cost equation. These techniques are invariant to the equation dropped.

Data and estimation

Variable cost data was obtained from 10 existing thermal power stations for the period 1984-85 to 1991-92, on a monthly basis. This included data on fuel costs, salaries, repairs and maintenance costs and administration costs. Data on units generated from these power stations was also collected.

The annual variable costs and generation for each powerstation was arrived at by aggregating the monthly costs and generation values For purposes of estimation, the administration costs are combined with salaries costs with salaries cost and are referred as labour costs.

For most studies which involve estimating a cost function, price indices are used as a proxy for per unit price, when it is difficult to determine the latter[5]. The wholesale price index for fuel, power light and lubricants, which is computed as a weighted price index using all-India weights is used as a proxy for fuel costs. Similarly, the wholesale price index for electrical machinery is used for price of materials. For computing the price of labour, since no appropriate price index is available, the average cost per employee in generation is used. All prices are adjusted to bring them to constant 1981-82 price levels.

The model uses the method of Iterative Three Stages Least Squares, also called the Seemingly Unrelated Regression Method[6] (Zellner)[7] to estimate the coefficients. Certain terms related with K were dropped as the associated coefficients estimated were not significant (i.e., not significantly different from zero). This resulted in an overall good fit of the equation. Thus only logK and

[5]An example is fuel costs. It is not possible to get data on the quantities of various fuels used in a power station as well as the exact prices at which they were procured during the year. Hence the alternate approach.

[6] For the detailed estimation process, see Annexure 4.1.

[7] Zellner, A. (1962) "An efficient method of estimating seemingly unrelated regressions and tests for aggregation bias," *Journal of the American Statistical Association*, Vol. 57.

$(\log K)^2$ are used in the estimation. Similarly, it was found that certain coefficients of the price terms were not significant. But these cannot be dropped without losing the theory behind a cost function which relates the behaviour of the cost of producing a certain level of output to the movement in prices. Indeed, having nonsignificant coefficients for the price terms shows that the generation cost is more affected by output than prices.

There were some gaps in the data set obtained from various power stations. These were dropped for analysis and only data from six power stations for the years 1984-85 to 1991-92 were used for the analysis. The six in the order of data compilation are: STPS1, STPS2, K(E)2, K(E)3, Amarkantak(1) and STPS3. The data set is ordered as follows, in a pooling of time series and cross section data. The first seven data points are figures for STPS1 for the years 1984-85 to 1991-92. The next seven are for STPS2 for the same years and so on. The coefficient estimates are given in Table 4.1.

Table 4.1: Estimates of co-efficient of the translog function

Coefficient	Estimate	Coefficient	Estimate
α_0	- 8 2347 (- 2.2713)	β_Q	1.8742 (1 6986)
α_F	0.0105 (0 0433)	β_{QQ}	-0.1688 (-1.0167)
α_M	0.8703 (4.0136)	β_{QF}	0.1163 (3 6862)
α_{FF}	0 3176 (0 8280)	β_{QM}	-0.0969 (3.1662)
α_{FM}	- 0 2935 (-0 7576)	γ_K	0.4804 (3.0311)
α_{MM}	0.3680 (0.9439)	γ_{KK}	-0 0780 (-2.5051)

Figures in parentheses are the T-statistics

The T-statistics indicate how significant the estimated coefficient is, in terms of determining the relationship between VC and an independent variable.

A general thumbrule is that if the T-statistic is greater than 2 in magnitude, then the coefficient is significantly different from zero. If it is less than 2, then a certain change in p_i or Q or K has no significant effect on VC. The R^2 of the variable cost equation was 0.93 which means that 93 per cent of the variation in the variable cost is explained by the independent variables on the right hand side of the equation.

It was found that some of the coefficient values were not statistically significant i.e., the associated independent variable does not affect the variable cost significantly. This is not a very unusual result because in most econometric runs it is not possible to find all the coefficients significant. Besides the translog form is more complex than a simple linear form and the coefficients of the interaction between terms, as for example α_{FM}, which is the coefficient of $\log P_F \log P_M$ may not be significant even though the coefficient for $\log P_F$ may be significant. The remedy to this is usually to drop the relevant terms like $\log P_F$, $\log P_M$ and then carry out the estimation one again, as this does not seem to explain the variation in VC. This could not be done with all terms whose coefficients are not significant without taking away the economic meaning of the function which is that a cost function is explained by exogenous factors like price and also by output. Besides, dropping these terms also lowered the R^2 of the equation to 0.88. Hence, these terms were retained. The significant terms are:

(a) α_0 the constant term is significant, indicating that even when all prices are zero, when capital invested is also zero and generation is nil, there will still exist some variable cost. This value is negative here, which can be explained as a receipt of income (maybe some advance funds, in the form of subsidy, for the project).

(b) α_M is the co-efficient of $\log P_M$. Looking at the materials cost share equation, if we find that α_M is the constant term. Therefore if all $\log P_i = 0$ and $\log Q = 0$, even then there would still be some positive materials share (maybe some repairs work are done even if the powerhouse has been shut down).

(c) β_{QF}, β_{QM} and ,γ_K, γ_{KK} are all significant. This indicates that the effect of a marginal increase in logQ on the fuel share is positive.

$$\beta_{QF} = \frac{\partial^2 logVC}{\partial logQlogP_F} = \frac{\partial\ fuelshare}{\partial\ logQ} = 3.6861 > 0$$

$$\beta_{QM} = \frac{\partial^2 \log VC}{\partial logQlogP_M} = -.0969$$

i.e., the effect of a marginal increase in logQ on the materials share is negative which means that the more the unit generated, that is the less the forced outages (and consequently the higher availability), the less (relatively) one has needed to spend on maintenance.

It is assumed that for the new thermal generation projects, the variable costs would behave as defined in the equation above[8].

4.3 A model for prioritisation

A description of the model for prioritisation of the ongoing thermal and hydel generation projects follows.

Q_{gn} is for generation in MUs from power station g in year n

K_{gn} is for investment in Rs. (in million) in g in year n

A_g is for capacity of power station g (MW)

B_g is the total project cost of power station g (Rs. million)

C_g is the cost of power station g (Rs. million) already incurred

Res(n) is the annual plan allocation for generation (Rs. million)

VC_{gn} is the variable cost of thermal power station g in year n (Rs. million)

p is the average revenue realised per unit sold (Rs./kWh)

[8] The behaviour of the historical costs depend on many factors such as age of the unit, size of the unit, technology etc. Assuming that the same characteristics hold for a newly commissioned plant. But since there is no data available to determine a cost function for new power stations, it is assumed that the cost fraction estimated for existing power stations would also supply to the new stations.

Then the maximisation of net benefit is as follows:

$$\underset{(Q_{gn},K_{gn})}{Max.} \sum_{g} \sum_{n} \left[pQ_{gn} - \sum_{m} VC_{mn}(Q_{gn},K_{gn}) - K_{gn} \right]$$

subject to the following constraints

$$Q_{gn} \le A_g \tag{1}$$

i.e., generation output (in MUs) from power station g in any year n cannot exceed the capacity of power station g (converted to million units).

$$\sum_{n} K_{gn} \le B_g - C_g \tag{2}$$

i.e., investment in any power station g over all the years under consideration cannot exceed the total cost of the project less the cost already incurred.

$$\sum_{g} K_{gn} \le Res(n) \tag{3}$$

i.e., in any year the total of investment made in all projects cannot exceed the plan allocation for that year.

$$\begin{aligned} Q_{gn} &> 0 \quad \text{if} \quad \sum_{n} K_{gn} \ge 0.95 \times B(g) \\ &= 0 \quad \text{otherwise} \end{aligned} \tag{4}$$

i.e., there can be positive generation only if there has already been atleast 95 per cent investment in the project. Since generation takes place only after all the equipment is duly installed and commissioned, this constraint becomes necessary.

This is an optimisation problem, which is non-linear in both the objective function and the constraints. Two variables that will be solved by the optimisation model are:

(i) K_{gn} - the amount of investment to be made for every project g for under consideration for every year n.

(ii) Q_{gn} - corresponding to the above K_{gn}, the output that would be generated by every g for every n under consideration.

The model was run using the General Algebraic Modelling System (GAMS) version 2.04. Before the model was run there were bounds given on the variables. Since the model was non-linear it was also necessary to give initial values for the variables. The model description is given in the Annexure 4.2.

Since the model is nonlinear, it is necessary to give some initial values for the variables. They are, of the following form.

Z(g,n) -- Based on the annual plan outlay, and looking at the sequence of commissioning of the various power plants, an initial estimate of the percentage of investments to be made in each of the projects is given. This is based on the commissioning schedule for projects as envisaged in the Annual Plan document. Also, other factors such as the cost already incurred on the project, the delay in commissioning etc. are also considered in arriving at this initial estimate. For eg. the revised allocation for Birsinghpur Units 1&2 was Rs. 150 crores for 1992-93. But keeping in view the delay in commissioning this project, an initial estimate of 70 per cent of the balance investment is provided for. Similarly for other projects, the initial estimates are made keeping in view the proposed commissioning schedule[9]. The columns of Z_{gn} multiplied by the respective balance project cost i.e., $(B_g - C_g)$, should add up to the proposed annual plan outlay.

[9] The assumption is that commissioning takes place if 95% of investment has already been made.

P(g,n) -- This gives the plant load factor at which the stations are expected to generate when commissioned. The PLF assumed are: Bansagar Tons - 40 per cent, Hasdeo Bango - 35 per cent, Maheshwar Hydel (6 units) - 46 per cent. (This again was made in consultation with experts in TERI keeping in view that they are also irrigation projects).

X(g,n) -- Is a table which gives the expected generation, in MUs which is obtained as the product of the assumed plant load factor and the capacity. This is consistent with the above commissioning schedule.

A word of caution is required here. Since the model was highly non-linear, it was necessary to put in certain bounds for Q_{gn} and K_{gn}. Since the objective is maximization of net benefit, the model will choose a higher Q if possible, subject to the upper bound. This is what has occurred for the years before the commissioning of the power houses. For the unconstrained maximization of net benefit, it would also be necessary to keep K_{gn} as small as possible. Therefore a small value of Rs. 0.011 lakh is assigned as the lower bound.

Therefore instead of choosing a lower bound, the model will choose the maximum capital that it can allocate to the projects so that they can be commissioned as early as possible, which means that Q_{gn} will take a higher value and net benefit can reach a maximum.

The variables and the equations in the model are then specified. Though there are only two variables, Q_{gn} and K_{gn}, a new variable Y_{gn} had to be defined (explanation follows) because of which it was necessary to put in two more equations.

The first three constraints correspond to (1), (2) and (3). The fourth constraint, is:

$$Q_{gn} > 0 \quad if \quad \sum_n K_{gn} \geq 0.95 \times B(g)$$
$$= 0 \quad otherwise$$

In order to put this into a form that the software can interpret, Y_{gn} is defined as:

$$Y_{gn} = Max. \left[0, \quad \frac{\sum_n K_{gn} - 0.95 \times B(g)}{mod(\sum_n K_{gn} - 0.95 \times B(g))} \right]$$

The denominator is the modulus of ΣK_{gn} - $.95*B(g)$ which takes just the magnitude and not the sign. If less than 95 per cent of the investment is made, the second expression in Y_{gn} will be negative and thus Y_{gn} will take the value 0. If Y_{gn} = 0, then Q_{gn} = 0. If more than 95 per cent of the investment is made, than Y_{gn} will take the value 1, thus indicating that the project can start generating. Generation Q_{gn} is defined as:

$$Q_{gn} = P(g,n) * A(g) * Y(g,n)$$

The last equation is the objective function which is expressed as the sum of net benefit from thermal power plants and net benefit from hydel power plants. The variable cost is considered only for thermal plants, because it is negligible for hydel power plants.

4.4 The results of the prioritisation model - base case scenario

For the base case, for the years 1992-93 and 1993-94, the actual allocated funds are taken. For the rest of the years, upto 1996-97, the rest of the plan allocation is divided in the ratio of the need based outlay for the various years (for a total

plan allocation of 3969.3 crores)[10]. Since it was likely that there would be some spillover effects into the next Plan, the year 1997-98 was also considered and the funds allocated was set at a level higher than that for 1996-97. This amount is, at the moment arbitrary.

In running the model it was found that the constraint for Q_{gn} led to certain complications. Hence, the constraint was modified as:

$$Q_{gn} \geq P_{gn} A_g Y_{gn}$$

When Y_{gn} takes the value zero, then, in order that Q_{gn} not be high, an upper bound on Q was given as a very small positive number. This number could not be zero because of the logarithmic form of the variable cost function, where $\log Q_{gn}$ is considered. Infact the bound is the expected benefits table X_{gn} where the elements of X_{gn} are taken as $P_{gn}A_g$. Also, lower bounds for the variables, as well as certain initial values from where the search for the optimal point is to begin, is given.

The detailed break-up of investments in the Eighth Plan required as on October 1992 and the investments proposed during the Eighth Plan are given in Table 4.2. Year-wise breakup of investments for each of the projects for the period 1992-93 to 1997-98 is as given in Table 4.3. The allocation of the Annual Plan resources to the various projects for the Eighth Plan and the spillover effect into the first year of the Ninth Plan shows that even by 1997-98, it is not possible to have the full investments made in Pench Thermal, Korba West Bank Extension and Maheshwar Hydel projects. The total resource allocation for the Bansagar Tons project and Birsinghpur Units 3&4 can get completed only by the first year of the Ninth Plan. The expected generation from the new power stations is given in Table 4.4.

[10]Source: Draft Proposal for the Eighth Plan - prepared for submission to the State Government and Planning Commission - October 1992)

Table 4.2: Proposed investments in generation projects		
	Investment during Eighth Plan (Rs.crores)	Investment Pending as of Oct. 1992 (Rs. crores)
Birsinghpur Units 1&2	269.28	269.28
Birsinghpur Units 3&4	602.27	639.87
Pench Thermal Units 1&2	98.57	485.63
Korba West Bank Extension Units 5&6	267.85	977.57
Bansagar Tons PH II and III	152.02	168.91
Hasdeo Bango	37.46	37.46
Maheshwar Hydel Units 1 to 6	286.12	606.19

Table 4.3: Annual investments in new power stations during the Eighth Plan (Rs. crores)						
Power stations	**92-93**	**93-94**	**94-95**	**95-96**	**96-97**	**97-98**
Birsinghpur Units 1 & 2	188.49	53.85	13.46	8 07	2.69	2.69
Birsinghpur Units 3 & 4	63 39	126.79	95.09	126 79	126 79	63 40
Pench Thermal Unit 1 & 2	0.48	0.48	24.27	24.27	24.27	24.27
Korba West Bank Extension Unit 5 & 6	6 84	6.84	29.33	48.88	78.21	97.76
Bansagar Tons PH II and III	8 44	16.89	25.34	33 78	33.78	33.78
Hasdeo Bango	11 24	7.49	5.62	7 49	3 75	1 87
Maheshwar Hydel 6 Units	0 61	0 61	60.62	42.43	60.62	121.24

Table 4.4: Expected generation from new power stations during the Eighth Plan (MUs)						
Power station	**92-93**	**93-94**	**94-95**	**95-96**	**96-97**	**97-98**
Birsinghpur Units 1 & 2	-	-	-	1887	2310	2310
Birsinghpur Units 3 & 4	-	-	-	-	-	943
Pench Thermal Unit 1 & 2	-	-	-	-	-	-
Korba West Bank Extension Unit 5 & 6	-	-	-	-	-	-
Bansagar Tons PH II and III	-	-	-	-	-	157
Hasdeo Bango	-	-	-	-	-	183
Maheshwar Hydel 6 Units	-	-	-	-	-	-

It is assumed that Birsinghpur units 1&2 will operate for 4500 hours during the first year of commissioning followed by 5500 hours during the subsequent years. As per the original schedule of commissioning of the Board, Birsinghpur units 1&2 were scheduled to go on stream in 1993-94. But, keeping in view the need to reduce the delays in commissioning of the other projects, some investments had to be provided, which resulted in a delay of two years in these two units. Birsinghpur Units 3&4 is expected to be commissioned only in the second half of 1997-98 (generation is calculated based on 2250 hours of operation), Hasdeo Bango and Bansagar Tons (power house II and III) are also expected to come on stream only in the second half of 1997-98 (again generation is calculated according to the plant load factor specified and halved).

4.5 High resource scenario

Tariff revisions based on 3.5 per cent rate of return only yield an additional Rs. 94 crores during the Eighth Plan. With this additional resources, the Board can bring on stream Hasdeo Bango and Bansagar Tons hydel power stations in 1996-97. If the rate of return of 5 per cent is achieved, the Board can raise an additional

Rs. 380.5 crores through tariff revisions as discussed in Chapter 3. The yearwise breakup of investments for generation is as given in Table 4.5 (assuming that 33 per cent of the additional resources are made available for generation).

Table 4.5: Additional resources available with 5 per cent rate of return

Year	Resources (Rs. crores)
1992-93	25.57
1993-94	21.28
1994-95	18.96
1995-96	25.76
1996-97	34.01
1997-98	37.51

Yearwise breakup of investments and the generation expected from the different projects for the Eighth Plan are given in Tables 4.6 and 4.7 respectively. The results show that Birsinghpur Units 1 & 2 can now be commissioned in 1994-95. In addition, the Board can bring in Birsinghpur Units 3&4 in 1997-98, and generation is estimated at 4500 hours. Pench and Korba West Bank Extension projects though cannot be completed within this planning period, can now be completed earlier than the base case since more resources are available. Bansagar Tons will start generation in the second half of 1996-97 as against generation in late 1997-98 in the base case. Hasdeo Bango project will come on stream in early 1996-97, thus yielding more benefits to the Board.

Table 4.6 : Yearwise breakup of investments for different projects for the Eighth Plan (Rs. crores)

Power station	92-93	93-94	94-95	95-96	96-97	97-98
Birsinghpur Units 1 & 2	215.42	40.39	8.08	2.69	2.69	2.69
Birsinghpur Units 3 & 4	63.39	139.47	114.11	139.47	145.81	31.69
Pench Thermal Unit 1 & 2	0.48	0 48	24.27	24.27	24.27	72.83
Korba West Bank Extension Unit 5 & 6	6.84	6.84	19 55	48.88	48.88	97 76
Bansagar Tons PH II and III	8.44	42.22	42 22	50.67	16.89	8.44
Hasdeo Bango	11.24	11.24	7.49	5.62	1.49	0.38
Maheshwar Hydel 6 Units	0.61	0.61	60.62	42 43	121.24	169 73

Table 4.7: Yearwise breakup of generation expected from the different projects for the Eighth Plan (MUs)

Power station	92-93	93-94	94-95	95-96	96-97	97-98
Birsinghpur Units 1 & 2	-	-	1887	2310	2310	2310
Birsinghpur Units 3 & 4	-	-	-	-	-	1887
Pench Thermal Unit 1 & 2	-	-	-	-	-	-
Korba West Bank Extension Unit 5 & 6	-	-	-	-	-	-
Bansagar Tons PH II and III	-	-	-	-	157	315
Hasdeo Bango	-	-	-	-	367	367
Maheshwar Hydel 6 Units	-	-	-	-	-	-

4.6 Power supply position in MPEB during Eighth Plan

Based on the additions as projected from the model, energy deficit for the base case scenario is expected to increase from 0.22 per cent in 1992-93 to almost 9 per cent in the terminal year of the Eighth Plan. For the high resource scenario, due to early commissioning of Birsinghpur units 1&2, the demand is expected to be fully met in 1994-95, as against a deficit of 7 per cent projected for the base case scenario (refer Table 4.8 and 4.9). In the terminal year, the deficit is estimated to reduce from 9 per cent for the base case scenario to 7 per cent for the high resource availability scenario. Thus it is imperative for the Board to consider all options available to raise additional resources to the extent of Rs.380 crores in order to reduce the deficit to the extent possible.

Table 4.8: Power supply position for base case resource scenario (MUs)

	1992-93	1993-94	1994-95	1995-96	1996-97
Existing thermal	11762	11762	11762	11762	11762
Existing hydro	1846	1846	1846	1846	1846
Benefits from R&M	0	0	545	545	545
Benefits from new power stations	572	997	1697	4259	4801
Existing central sector generation	6650	6650	6650	6650	6650
Total availability	20830	21255	22500	25062	25604
Energy demand (14 th EPS)	20878	22613	24391	26182	28104
Surplus/(-)deficit	-48	-1358	-1891	-1120	-2500
Surplus/(-)deficit %	-0.23	-6.01	-7 75	-4 28	-8.90

Table 4.9: Power supply position for high resource scenario (MUs)

	1992-93	1993-94	1994-95	1995-96	1996-97
Existing thermal	11762	11762	11762	11762	11762
Existing hydro	1846	1846	1846	1846	1846
Benefits from R&M	0	0	545	545	545
Benefits from new power stations	572	997	3584	4682	5325
Existing central sector generation	6650	6650	6650	6650	6650
Total availability	20830	21255	24387	25485	26128
Energy demand (14th EPS)	20878	22613	24391	26182	28104
Surplus/(-)deficit	-48	-1358	-4	-697	-1976
Surplus/(-)deficit %	-0 23	-6.01	-0.01	-2.66	-7.03

Annexure 4.1

A general estimation model

Any functional relationship can be represented in an econometric form as

$$y = \beta_1 x_1 + \beta_2 x_2 + \dots\dots + \beta_k x_k + u$$

where y is the dependant variable, and the x_1, x_2, ... x_k are the independent variables, β's are the coefficients to be estimated, 'u' is a random error term, which is needed to capture all those unexplained factors of y, which x_1, x_2, ... x_k cannot capture.

This equation may be represented in matrix form as :

$$\mathbf{y} = \mathbf{X}\beta + \mathbf{u}$$

$$y = \begin{bmatrix} y_1 \\ y_2 \\ \cdot \\ \cdot \\ \cdot \\ y_k \end{bmatrix} \quad X = \begin{bmatrix} \cdot & \cdot & \cdot & \cdot & \cdot & \cdot \\ x_1 & x_2 & \cdot & \cdot & \cdot & x_k \\ \cdot & \cdot & \cdot & \cdot & \cdot & \cdot \end{bmatrix} \quad \beta = \begin{bmatrix} \beta_1 \\ \beta_2 \\ \cdot \\ \cdot \\ \cdot \\ \beta_k \end{bmatrix} \quad u = \begin{bmatrix} u_1 \\ u_2 \\ \cdot \\ \cdot \\ \cdot \\ u_n \end{bmatrix}$$

The central problem is to obtain an estimate of the unknown β vector. For this purpose u = y - Xβ is minimised.

Instead of minimising u, we minimise u^2

Since u^2 will be u'u where u'u is the transpose of u,

$u'u = (y-X\beta)'(y-X\beta)$

or $u'u = y'y - 2\beta X'X\beta + \beta'X'X\beta$

Minimisation of u'u with respect to β means

$$\frac{\partial(u'u)}{\partial\beta} = -2X'y + 2X'X\beta$$

A necessary condition for the attainment of a minimum is that the above first order derivative is equal to 0.

i.e.,

$$\frac{\partial(u'u)}{\partial\beta} = 0$$

$$\text{i.e.,} \quad -2X'y + 2X'X\beta = 0$$

$$\text{So} \quad X'X\beta = X'y$$

$$\text{i.e.,} \quad \beta = (X'X)^{-1}X'y$$

This will give the entire matrix of coefficients once the numbers of x and y are fed in.

In the functional form used in this project, the β matrix here will conform to all the α, β, and γ to be estimated. The X matrix is the matrix whose columns are 1, $\log P_F$, $\log P_M$, $\log P_L$, $\log P_F \log P_F$ and so on including all the terms involving logQ and logK. The y vector is the vector of logVC.

Once the relevant figures for the entire data set for log VC and all the independent variables are fed in, 'β' is the coefficient vector to be estimated in the manner above.

The seemingly Unrelated Regression Estimation method is a modification to the above process, which is used for the estimation of a system of simultaneous, as in this model.

Annexure 4.2

A model for priotisation of generation projects

$ Title MPEB Prioritising for MPEB

MPEB is interested in prioritising its investments out of the available capital, it has identified certain areas where investment can be made - generation, transmission distribution, repairs and maintenance (CEA approved and awaiting approval), with the total amount of investment envisaged. This model will provide a rationale for prioritising investments by using a programming approach. The objective will be to maximise the net benefit of a particular scheme, subject to relevant constraints, where net benefit is the difference between gross benefit (as a function of energy) and total cost of the scheme (represented as a function of energy). Gross benefit is defined as the revenue generated as a result of undertaking a particular scheme (assuming consumer prices to be fixed). Cost is the total cost comprising of fixed cost and variable cost.

```
Option Limrow = 10000;
Option Domlin = 50;
Sets  N Years                      /92-93, 93-94, 94-95, 95-96, 96-97,
                                   97-98/

      G All Generation Projects    /B12, B34, P1, KWBEX, BT, HB, MH/
      M(G) Thermal Projects        /B12, B34, P1, KWBEX /
      L(G) Hydel Projects          /BT, HB, MH /

Alias (N,NJ)
*     B12    -    Birsinghpur Unit 1&2, B34 - Birsinghpur Unit 3&4, P1 -Pench
                  thermal,
*     KWBEX  -    Korba West Bank Extension, BT - Bansagar Tons, HB -
                  Hasdeo Bango,
*     MH     -    Maheshwar Hydel

Parameter A(G) Capacity (MU)     / B12 3679.2, B34  3679.2, P1 3679.2,
                                 KWBEX 3679.2, BT 788.5, HB 1051.2, MH 3504/
Parameter B(G) Capacity cost     / B12 7232, B34 7005.8, P1 5347.2,
              (Rs. Million)      KWBEX 9775.7 BT 5780.2, HB 753.8, MH 6140/
Parameter C(G) Incurred cost     / B12 4539.2, B34 666.1, P1 492.2, KWBEX 0,
              (Rs. Million)      BT 4091.1, HB 379.2, MH 78.1 /
Parameter Res(N) Annual Plan     / 92-93 2816.5, 93-94 2217.4, 94-95 2574
              (Rs. Million)      95-96 2937, 96-97 3356.1, 97-98 3500 /
```

Scalars	Price	Average revenue realised in Rs. / 1.15 /
	C1	Coefficient of translog α_0 / -8.2346954 /
	C2	α_F / 0.0105424 /
	C3	α_M / 0.8703022 /
	C5	α_{FF} / 0.3175840 /
	C6	α_{FM} / -0.2935301 /
	C8	α_{MM} / 0.3679595 /
	C11	β_Q / 1.8741847 /
	C12	β_{QQ} / -0.1688398 /
	C13	β_{QF} / 0.1162963 /
	C14	β_{QM} / -0.0969134 /
	C16	γ_K / 0.4804463 /
	C17	γ_{KK} / -0.0780311 /
	LPF	Log (P_F) / 5.229536 /
	LPM	Log (P_M) / 5.159663 /
	LPL	Log (P_L) / 6.344714 /
	TOL	Tolerance / 0.00001 /

Parameter		
	C4	α_L Coefficient of LPL
	C7	α_{FL}
	C9	α_{ML}
	C10	α_{LL}
	C15	β_{QL}
	Temp1	
	Temp2	
	Temp3	
	Const	Adding all constant terms ,

```
C4     =   (1 - C2 - C3); C7 = (- C5 - C6); C9 = (-C6 - C8), C10 = (C5 + 2*C6 + C8); C15
           = (-C13 -C14);
Const  =   C1 + C2*LPF + C3*LPM + C4*LPM + .5*C5*LPF*LPF + C6*2*LPF*LPM -
           2*C7*LPF*LPL + C8*LPM*LPM - C9*LPM*LPL + C9*LPL*LPL ;
Temp1 =    C12*.5;
Temp2 =    C13*LPF + C14*LPM + C15*LPM;
Temp3 =    Temp1 + Temp2;

Display C4, C7, C9, C10, C15, Temp1, Temp2, Temp3, Const;
```

Table X(G,N) Expected Benefits (MU)

	92-93	93-94	94-95	95-96	96-97	97-98
B12	20	20	20	1887 43	2310.74	2310.74
B34	1.84	1 84	1.84	1 84	1 84	943.715
P1	1 84	1.84	1.84	1 84	1 84	1 84
KWBEX	1 84	1 84	1 84	1 84	1 84	1.84
BT	019	019	019	019	019	157 57
HB	.105	.105	105	.105	105	183 76
MH	.35	.35	.35	.35	35	.35

Table Z(G,N) Initial Investment Shares						
	92-93	93-94	94-95	95-96	96-97	97-98
B12	.7	.2	0.05	0.03	0.01	0.01
B34	.1	2	.15	.2	.2	0.1
P1	0.001	.001	.05	.05	.05	05
KWBEX	.007	.007	.03	.05	.08	.1
BT	05	.1	.15	.2	.2	.2
HB	.3	.2	.15	.2	.2	.05
MH	0.001	0.001	.1	.07	.1	.2

Table P(G,N) Assumed Plant Load Factors.						
	92-93	93-94	94-95	95-96	96-97	97-98
B12	.05	.05	.05	.7	.7	.7
B34	.05	.05	.05	.05	.05	.05
P1	01	.05	.05	.05	.05	.05
KWBEX	.05	.05	.05	.05	.05	.05
BT	01	.01	.01	.1	.1	.40
HB	01	.01	.05	.05	.05	.35
MH	.01	01	.01	.01	.01	.46

Parameter NPAR(G)

NPAR(G) = B(G) - C(G)
Display NPAR ,
Variables Q(G,N) (Generation output in year n)
K(G,N) (Investment for G in year n)
Y(G,N) (New variable)
TP(M,N)
PC(M,N)
Netben net benefit ,

Positive Variables Q,VC,K ;

```
Equations      KAP (G,N)       (Capacity constraint for G)
               Inves(G)        (Investment in G)
               Anninv(N)
               Outpt(G,N)      (Generation constraint for G)
               Dummy(G,N)
               Temp(M,N)
               Partco(M,N)
               MBDEF           (Net benefit definition) ;

Kap(G,N)       ..    Q(G,N) = L = A(G) ;
Inves(G)       ..    Sum(N), K(G,N) = L = B(G) - C(G) ;
Anninv (N)     ..    Sum(G, K(G,N)) = E = Res(N) ;
Dummy (G,N)    ..    Y(G,N) = E = Max(0, (Sum(NJ$(ORD(NJ) LE ORD(N), K(G,NJ))
                     - 95*B(G)))/ABS(Sum(NJ$(ORD(NJ) LE ORD(N)), K(G,NJ)
                     - .95*B(G) + Tol) ;
Outpt(G,N)     .     Q(G,N) = E = P(G,N)*A(G)*Y(G,N) ,
Partco(M,N)    .     PC(M,N) = E = Log(Q(M,N))*(C11 + Temp1*Log(Q(M,N)) ;
NBDEF          .     NETBEN = E = SUM(M, Sum(N, (Q(M,N)*1.73 - Exp(Const +
                     VC(M,N) + C16*Log(K(M,N) + C(M) + C17*.5*Log(K(M,N) +
                     C(M))**2) - K(M,N))) + Sum(L, Sum(N, Q(L,N)*1.73 - K(L,N))) ;
*Bounds for variables
*Lower Bounds
Q.LO(G,N) = X(G,N) ;
K.LO(G,N) = .0011 ,
*Upper Bounds
K.UP('B12',N) = Z('B12',N)*(B('B12') - C('B12')) ;
K,UP('P1',N) = Z('P1',N)*(B('P1') - C('P1')) ;

Model MPEB /ALL/ ,
*Initial values
Q.L(G,N) = Q LO(G,N) ,
K.L(G,N) = Z(G,N)*(B(G) - C(G)) ,

Display Q.L,K,L ;
Solve MPEB maximizing NETBEN using DNLP ;
```

CHAPTER 5

RENOVATION AND MODERNIZATION OF POWER STATIONS

An alternative measure to overcome energy as well as peak shortages by new capacity additions, is to operate the existing power stations more efficiently. Several case studies in India and other countries have proved that renovation and modernization (R&M) of the existing generating units is a more cost effective option than adding new generation capacities. Cost of renovation per KW is estimated at Rs. 8,250 only as against the cost of new installation of Rs. 25,000 - 30,000 at 1992-93 price levels.[1] In an economy constrained by the availability of resources, the need and importance of renovation and modernization needs no further emphasis.

The R&M programme (Phase I) was launched during 1984-85, with the basic objective to improve the generation and capacity utilization of the old units. The thrust area was mainly enhancement of reliability and efficiency of the thermal units with improvement in environment and safety conditions as secondary benefits. MPEB, under the Phase I of the R&M programme, had undertaken work at Korba, Amarkantak and Satpura power stations. The total estimated cost of these activities as on March 1992, was Rs. 80.19 crores (refer Table 5.1). The resources have been raised both under central loan assistance (Rs. 22.53 crores or 28 per cent) as well as the state plan (Rs. 57.66 crores or 72 per cent). While most of the work relating to increasing plant load factor and environment related activities for the power station were covered under central loan assistance, activities under state plan included procurement of spares, conversion of existing fuel system to LSHS, modification of fire protection systems etc. As at the end of March 1992, Rs. 68.18 crores have already been spent on the R&M activities and the balance Rs. 12.01 crores is the spill over to the Eighth Plan. In the proposal for Annual Plan for 1993-94, an outlay of Rs. 7.9 crores and

[1]Environmental upgradation through renovation and modernization, B.M. Pant, Power Finance Corporation.

Rs. 1.07 crores have been proposed for 1992-93 and 1993-94 respectively, against the approved outlay of 12.01 crores in 1992-93. It is suggested that the Board must find resources for the balance amount of Rs. 3.04 crores during 1994-95 to complete all the pending R&M works planned under Phase I. Benefit of additional 528 MUs is estimated as a result of these R&M activities, from 1992-93 onwards.

Table 5.1: Details of R&M activities of MPEB under Phase I (Rs. lakhs)

Power station	Cost (3/1992)	Exp. upto 3/92	Expected expenditure in 1991-92	Outlay proposed for 1992-93
Korba (CLA)	321 05	313.05	8.24	
Korba (SP)	1663.53	1312.06	177.74	173.73
Satpura (CLA)	1807 64	1297.5	465.79	44.35
Satpura (SP)	2527 76	1740.17	288.26	499.11
Amarkantak (CLA)	123.91	120.35	3 56	0
Amarkantak (SP)	1575 89	415.78	675.95	484.16
Total	8019.78	5198.91	1619.54	1201.34

CLA: Central loan assistance scheme
SP: State Plan

Under R&M Phase II, MPEB has drawn a plan for further extending the works at Korba, Satpura and Amarkantak power stations and also start the renovation and modernization activities at Korba (West) power station. The total cost of these activities is estimated at Rs. 86.36 crores as on March 1992 and all the resources are expected to be raised from the central loan assistance programme. The R&M activities at all the four power stations were initiated in early 1991 and were estimated to yield a benefit of 545 MUs of additional energy every year, from 1994-95 onwards. This is equivalent to 130 MW of new capacity assuming 4200 kWh/kW factor as recommended by the Planning commission. Cost per kw for the R&M activities (excluding the cost of ESPs), is estimated to range between 7 to 25 per cent of the cost of new capacity (refer Table 5.2).

Table 5.2:	**Cost benefit analysis of R&M activities of MPEB.**			
Power station	**Cost excluding the cost of ESP (Rs. lakhs)**	**Benefits (MUs)**	**Benefits (KW)**	**Cost/kW (Rs./KW)**
Korba (East)	1034.5	195	46429	2228
Satpura	1482.0	170	40476	3661
Amarkantak	1473.0	105	25000	5892
Korba (West)	1126.0	75	17857	6306

It is therefore evident from the above table that the R&M programme drawn by the Board is very cost effective and the Board must aim at completing these activities at the earliest to reap the benefits. This is even more important considering the fact that as per the base case analysis carried out in Chapter 4, it is seen that only Birsingpur units 1 and 2 are expected to be commissioned during the Eighth Plan, due to paucity of resources. The cumulative expenditure on R&M activities at end of March 1992 was Rs. 38.2 crores and Rs. 37 crores have been proposed during the Eighth Plan as per the draft Annual Plan 1993-94 (refer Table 5.3). This leaves a shortfall of Rs. 11.16 crores for the entire work on R&M to be completed in the Eighth Plan. It is suggested that the Board should ensure that these resources are made available and the R&M activities completed on schedule in 1994-95. The Board needs to pursue the proposals with the Power Finance Corporation, which provides resources outside the Plan. While priortising among the various R&M activities, it is suggested that those which directly increase the efficiency and plant load factor of the power stations should be completed first. Investments in procuring spares, enhancing coal handling plants etc. could be taken up subsequently.

Table 5.3:	**Details of R&M Phase II Plan for MPEB (Rs. lakhs)**			
Power station	**Cost (Rs. lakhs)**	**Exp. as on 3/91**	**Anticipated exp. in 1991-92**	**Proposed outlay 1992-93**
Korba (East)	2834.50	913.04	727.20	709.00
Satpura	1802.61	177.52	293.78	682.85
Amarkantak	2873 00	1542.66	209.14	316.20
Korba (West)	1126.02	4.20	62 68	309.95

CHAPTER 6

FUTURE WORK PLAN

An attempt has been made in this report to prioritise investments in generation projects for the Eighth Plan. The additional resources that can be raised through tariff increases has been estimated based on certain assumptions such as timely receipt of subsidy, improvement in revenue outstandings, etc. Generation investments have been prioritised for two scenarios: (i) base case scenario where current limited availability of resources of Rs. 3969 crores is used as a resource constraint; and (ii) a high growth scenario where additional resources to the tune of Rs. 380 crores are taken into consideration. A brief note on the R&M activities of the Board is also included with this report.

As per the terms of reference, the following items need further action:

(1) Prioritising investments in transmission and distribution: Prioritization exercise has been carried out for investments in generation. As far as transmission and distribution is concerned the following approach would be adopted.

Evacuation lines for the power stations that are expected to be commissioned in the Eighth Plan will be identified. The schedule of commissioning of these lines will have to coincide with the commissioning of the respective power stations. A detailed analysis will be carried out to determine the load centres where substantial growth is expected during the Eight Plan. Investments in distribution will be prioritised according to the rate of increase in demand in the various distribution circles. It is requested that the Board identify a nodal transmission person for providing assistance to identifying the need for various lines as well as to get information on load centres and there related investments.

(2) Identify areas where dis-investment or reduced investment is justified: Returns on investments (excluding land) during the last 3 to 5 years will be reviewed to determine whether the investments should continue or there should be partial or total dis-investment in some of these areas. An attempt will be made to also look at land holdings of the Board to see if there are any constraints in using them to raise any additional resources.

(3) To affect economy in expenditure by adopting appropriate measures in areas where the Board's costs are higher compared to other Boards: Detailed costs of operation and maintenance at power stations, transmission and distribution will be collected for each of the distribution circles as well as a breakup of the salaries, travel, overtime, office expenditure etc. to determine areas where cost effectiveness can be initiated. This item would require substantial amount of data from the Board's field offices and the cooperation of the Board is sought in order to collect the data required.

(4) Identify options for financing capital requirements: This report has identified some institutions who could be considered to provide possible finance for projects. Discussions will be held with each of these financing institutions to determine if there exists any special conditions for financing power projects as well as to determine whether there are any restrictions on lending to the Board. An attempt will also be made to look at the possible changes that may need to be made to the Electricity Supply Act, if the Board has to go to the market for procuring funds.

A detailed list of data requirements is being sent to the Board separately with this report. TERI researchers plan to visit the Board in the second week of July to further data collection efforts and to have discussions with the Board officials. It is suggested that the data required be compiled and be made available to TERI researchers when they visit the Board in early July. On the assumption that the entire data required will be made available by the end of July, TERI will submit the final report by the end of August.